BEFORE THE

PUBLIC UTILITIES COMMISSION
OF THE
STATE OF RHODE ISLAND
AND PROVIDENCE PLANTATIONS

IN THE MATTER OF

The Application of New England	**)**	
Gas Company for an Increase	**)**	**Docket No. 3436**
In its Gas Cost Recovery Charge	**)**	

DIRECT TESTIMONY OF WITNESS
BRUCE R. OLIVER

On Behalf of

The Division of Public Utilities

OCTOBER 12, 2004

TESTIMONY OF BRUCE R. OLIVER
Docket No. 3436
October 12, 2004

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Bruce R. Oliver. My business address is 7103 Laketree Drive, Fairfax Station, Virginia, 22039.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Revilo Hill Associates, Inc., and serve as President of the firm. I manage the firm's business and consulting activities, and I direct its preparation and presentation of economic, utility planning, and policy analyses for our clients.

Q. ON WHOSE BEHALF DO YOU APPEAR IN THIS PROCEEDING?

A. My testimony in this proceeding is presented on behalf of the Division of Public Utilities (hereinafter "the Division").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. This testimony addresses issues relating to the September 1, 2004 Annual Gas Cost Recovery (GCR) filing of New England Gas Company (hereinafter “NEG” or “the Company”).

Q. IS NEG PROPOSING TO INCREASE ITS GCR CHARGES?

A. Yes. The Company proposes to increase its GCR charges for all firm sales service rate classifications. The Company also proposes to adjust its charges for marketer transportation services and increase its charges for Natural Gas Vehicle Service.

Q. HOW DO NEG'S PROPOSED GCR CHARGES COMPARE WITH THE COMPANY'S CURRENT GCR CHARGES BY RATE CLASS?

A. Exhibit BRO-1 provides a comparison of the Company's current and proposed GCR charges. That comparison indicates increases in NEG's GCR charges would vary by rate classification. Residential and Small C&I charges would increase less than 1.6%, while increases for Medium, Large and Extra-Large C&I customers would range from about 1.8% to 4.1%.

Q. WILL CUSTOMERS' BILLS INCREASE IN PROPORTION TO THE PERCENTAGE INCREASES IN GCR CHARGES SHOWN IN EXHIBIT BRO-1?

A. No. Customers' bill will reflect the combined impacts of the GCR charges that the Company proposes in this proceeding and the DAC increase that NEG seeks in Docket 3548. Witness Czekanski presents an analysis of bill impacts resulting from the combined impacts of those increases in Schedule PCC-4. That analysis depicts ranges of impacts for each rate class based on varying levels of annual gas use. The ranges of impacts that result from the Company's analyses are as follows:

Residential Heating	3.1% - 3.3%
Residential Non-Heating	14.5% - 17.5%
C&I Small	1.7% - 2.0%
C&I Medium	3.8% - 3.9%
C&I LLF Large	4.7% - 4.8%
C&I HLF Large	5.9% - 6.0%
C&I LLF Extra-Large	6.6% - 6.7%
C&I HLF Extra-Large	5.0% - 5.1%

Q. WHY ARE THE COMPANY'S CALCULATED PERCENTAGE INCREASES FOR RESIDENTIAL NON-HEATING CUSTOMERS SO LARGE?

A. There is an error in the Company's filed bill impact analyses for the Residential Non-Heating customers in both this Docket and the currently pending DAC proceeding, Docket No. 3548. In the bill impact analyses filed in these proceedings, NEG mistakenly utilized a DAC credit of $0.2480 per therm. When the appropriate current DAC factor of $0.0248 per therm is used, the combined impact of NEG's proposed GCR and DAC charges for Residential Non-Heating customers yields annual bill increases ranging from **1.75% to 2.07%**. (See Exhibit BRO-2 attached to this testimony.) None of the bill comparison for other classes appears to be affected by that inadvertent error.

Q. WHY ARE THE PERCENTAGE INCREASES IN GCR CHARGES NOT UNIFORM ACROSS RATE CLASSES?

A. Three basic factors contribute to the differences in percentage increases in GCR charges by rate class that NEG proposes. Those are:

1. Differences in the rates of change in the size of the GCR cost components; and

2. Differences in the magnitude of over- or under-collections of costs by GCR component; and

3. Differences in the manner in which the five components of GCR costs are allocated among classes.

Exhibit BRO-3, pages 1 and 2, depicts the changes in NEG's gas costs between its 2003-04 and 2004-05 GCR periods. Page 1 indicates that the Company's projected costs of gas for its 2004-05 GCR period, without consideration of reconciliation adjustments for past over- (under-) recoveries, have increased 15.0% from the level that NEG projected one year earlier. Moreover, increases in Supply Variable Costs account for nearly $30 million of the overall $31 million increase in

NEG's annual gas costs. Page 2 provides data comparable to that shown on Page 1 with reconciliations for past over- (under-) recoveries included. When reconciliation amounts are reflected, the overall changes in GCR costs declines to 9.0%. Yet, the increase in Supply Variable Costs totals $26.1 million while the overall increase in GCR costs is less than $20.4 million. The difference is primarily attributable to reductions in Supply Fixed Cost, Storage Fixed Cost, and Storage Variable Product Cost recovery requirements that result from over-collections for those GCR components during the 2003-04 GCR period.

Pages 3 and 4 of Exhibit BRO-3 illustrate the magnitude of the differences in the over- and under-recovery amounts by GCR cost component that influence the overall dollars by GCR cost component that NEG seeks to recover through its proposed GCR rates. The detail provided on page 3 of Exhibit BRO-3 demonstrates that cost recoveries for the 2003-04 GCR period have not been uniform across cost components. Although over-recovery balances are projected for four of the five GCR cost components at the end of the current GCR year, Supply Variable Costs are expected to be nearly $16 million under-recovered. As a result of those past over- (under-) recoveries, the Supply Variable Cost component of NEG's proposed 2004-05 GCR rates is increased by more than $16 million to offset past under-recoveries. On the other hand, cost recovery requirements all other GCR components are reduced to reflect past over-recoveries.

Exhibit BRO-3, page 5, compares the allocation factors that are used to allocate GCR costs by component among rate classes. The observable differences in the factors used to allocate costs among rate classes do not appear to be dramatic, but those differences are large enough to have noticeable impacts on the resulting GCR rates by class. In particular, the Residential and Small Commercial classes derive somewhat greater benefit from past over-recoveries of Supply Fixed Costs, while Large and Extra-Large High Load Factor C&I rate classifications carry more of the burden of past under-collections associated with Supply Variable Costs.

Q. ARE THE GCR CHARGES THAT NEG PRESENTS THROUGH THE TESTIMONY OF WITNESS CZEKANSKI AND SCHEDULE PCC-1 PROPERLY COMPUTED?

A. In general, the mathematical computations upon which those charges are based appear to be accurate. Although certain minor elements within those calculations appear questionable, I have determined that they have no noticeable impact on the resulting charges by rate class that NEG proposes. Additionally, I note that, in the limited time available for this review, I have not had an opportunity to fully audit the input data that NEG has used in its GCR computations. Thus, much of that input data relating to costs, revenue and units of service has been accepted at face value.

I must observe, however, that the forecasted sales data NEG uses in this proceeding exhibit unexpected and unexplained variations from the patterns of monthly sales found in forecasted sales that NEG presented last year for the current GCR period. Such unexpected variations in forecasted monthly sales patterns pervade both the Company's aggregate sales data and the sales for individual rate classes. It is also noteworthy that in comparison to the Company's forecasted sales for its 2003-04 GCR period, the sales forecast used in this proceeding shifts significant sales volume out of the months of June through October (i.e., summer months) and into the January to May period (i.e., primarily winter months).

Exhibit BRO-4 shows a comparison of forecasted total sales by month and the changes in those sales by month. Generally, when forecasts are prepared on the basis of normal weather expectations and overall growth in sales is relatively small, changes in sales levels by month from one forecast to the next are expected to be small. Yet, the Company's forecasted sales for September 2004 decline more than 21% from the prior year's projection, while increases of more than 200,000 MMBtu are observed for the months of February, March and May. Changes in forecasted sales for comparable months of the magnitude reflected in these observations from Exhibit BRO-4 warrant further explanation.

Q. HAS NEG MADE ANY SIGNIFICANT CHANGES IN THE MANNER IN WHICH IT COMPUTES ITS PROPOSED GAS COST RECOVERY RATES?

A. No, it has not. The methods it has used to calculate its GCR rates match closely with those that it used in its last annual GCR filing, although one notable change can be observed in the manner in which capacity release credits are reflected in the computation of the Supply Fixed Cost component of NEG's GCR charges. In the Company's September 2, 2003 filing in this docket, Capacity Release Revenues were shown as a separate line item in the calculations on page 2 of Attachment MJH-1. In the comparable schedule in NEG's September 1, 2004 filing (Schedule PCC-1, page 2), the line labeled Capacity Release Revenue (line 3) reflects a zero dollar entry, but line 1 on that page notes that the Company's reported Supply Fixed Costs are net of Capacity Release Revenue.[1]

This change in the manner in which the Company reflects Capacity Release Revenue does not appear to have any substantive impact on the calculation of the Company's Supply Fixed Cost factors. Rather, this change in the Company's presentation of data relating to Capacity Release Revenue is apparently intended to address concerns regarding the Confidentiality of portions of that revenue. However, the total amount of estimated Capacity Release Revenue is shown on

[1] A similar change in the presentation of Capacity Release Revenue is found on page 1 of Schedule PCC-3 in NEG's September 1, 2004 filing.

Schedule GLB-1 within the same filing without any mention of confidentiality. In this context, I believe it would have been more appropriate, from the perspective of facilitating Division and Commission understanding of these matters, for the Company's total estimated Capacity Release Revenue to be shown as a separate entry on page 2 of Schedule PCC-1 and in other related schedules. If in the future, NEG has concerns regarding the confidential nature of such information, it should discuss those concerns with the Commission and the Division prior to making its annual GCR filing, and at a minimum, provide any confidential information in a separate, non-public document submitted simultaneously with the Company's filing of public information.

Q. WHAT IS THE MAGNITUDE OF NEG'S ESTIMATED CAPACITY RELEASE REVENUE FOR ITS 2004-05 GCR PERIOD?

A. Schedule GLB-1, attached to the September 1, 2004 testimony of NEG witness Beland reflects Capacity Release Revenue for the 2004-05 GCR period totaling **$5,307,492**. NEG's capacity release revenue has two major components. Those are (1) revenue from releases of capacity to marketers providing gas supply to NEG customers in Rhode Island and (2) revenue from NEG's asset management contract with ConocoPhillips. The contribution of each of those revenue sources to the

Company's estimated total capacity release revenue for the 2004-05 GCR period is provided in a CONFIDENTIAL response to Commission Data Request COMM 1-13. I will not recite those amounts herein.

Q. HOW DOES THE COMPANY'S ESTIMATE OF 2004-05 CAPACITY RELEASE REVENUE COMPARE WITH NEG'S ESTIMATED AND ACTUAL CAPACITY RELEASE REVENUE FOR THE 2003-04 GCR PERIOD?

A. Attachment MJH-1 to NEG's September 2, 2003 filing in this docket incorporated a credit of **$860,800** to Supply Fixed Costs for estimated Capacity Release Revenue. That equates to only 16.2% of the estimated level of Capacity Release Revenue NEG includes in its present filing. NEG's Actual Capacity Release Revenue for the 12 months ended June 30, 2004 as detailed on Schedule 1, page 1, of NEG's Annual Gas Cost Recovery Reconciliation filing reflects capacity release revenue of $2,400,127. In addition, Schedule 2, page 1, of that reconciliation filing shows "Credits from Marketer Releases" which total to $3,108,212. Thus, it appears the total Capacity Release Revenue for the 12 months ended June 30, 2004 was in excess of **$5.5 million**.

Q. WHY DOES IT APPEAR THAT THE COMPANY'S ESTIMATE OF CAPACITY RELEASE REVENUE FOR ITS 2003-04 GCR PERIOD SUBSTANTIALLY UNDERSTATED ITS ACTUAL CAPACITY RELEASE REVENUE?

A. When NEG submitted its annual filing last year for its 2003-04 GCR period, the terms of its agreement with ConocoPhillips had not been finalized, and according to NEG personnel, considerable uncertainty existed regarding the level of asset management revenue it would receive. In that context, NEG was reluctant to speculate in that filing regarding the amount of asset management revenue it could expect.

Based on my understanding of the timing of events relating to the completion of that agreement and the submission of the Company's GCR filing, I find no reason to conclude that NEG withheld information regarding expected asset management revenue or purposefully understated its expected revenue at that time. Furthermore, now that a higher level of overall capacity release revenue has been achieved, the Company must assume the burden of justifying any significant reduction from that level as the basis for setting GCR charges and measuring incentive compensation for subsequent periods.

Q. ARE THERE ANY CHANGES IN NEG'S METHODS FOR COMPUTING ITS PROPOSED GCR RATES THAT YOU WOULD RECOMMEND?

A. Not at this time. However, as noted in the testimony I filed on October 8, 2004 in Docket 3548, changes in NEG's use of LNG may necessitate a re-assessment of the percentage of LNG cost that is recovered through the DAC.

During the winter of 2003-04 the manner in which the Company dispatches LNG changed, and the overall volume of LNG used increased significantly. Despite the fact that the winter of 2003-04 had fewer heating degree days than the prior winter, LNG use during the winter of 2003-04 increased nearly 40%. That increase in LNG use was the result of the Company's economic dispatch of LNG during period of high system demand. Moreover, as economic dispatch of LNG increases, the proportion of total LNG use that is attributable to the maintenance of system pressures would be expected to decline.

At present, 20.39% of NEG's LNG costs are designated for recovery through DAC charges to reflect the Company's use of LNG in the maintenance of system pressures. That allocation was based on an examination of the Company's historic LNG use patterns. At that time there was no anticipation of increased economic dispatch of LNG. As a result, no mechanism was established for adjusting the percentage of LNG costs that would be recovered through DAC charges in the event the portion of the Company's LNG use that is attributable to maintenance of system pressures changes. If increased economic dispatch of LNG continues, the Commission may need to revisit the manner in which the allocation of LNG costs between gas supply (i.e., recovery through the GCR) and maintenance of system pressures (i.e., recovery through the DAC) is determined. For this reason, I recommend that the Commission recognize that, for the purposes of this proceeding, NEG has computed its allocation of LNG costs in accordance with its tariff and agreements reached in Docket No. 3401. However, I also suggest that the Commission require NEG to track its LNG use over the next winter and provide an assessment of the impacts of changes in its LNG dispatch on the appropriate allocation of LNG costs between the GCR and DAC prior to the time of its next annual GCR and DAC filings.

Q. HAVE YOU REVIEWED THE DETAIL OF THE ANNUAL GAS COST RECOVERY RECONCILIATION REPORT THAT IS ATTACHED TO MR. CZEKANSKI'S TESTIMONY AS SCHEDULE PCC-2?

A. Yes, I have. In general, the data and calculations presented in that report appear to be accurate. A couple of minor elements of that report appear questionable, but I have determined those elements of the Company's reconciliation report would have no noticeable impact on the charges by rate class that NEG proposes.[2]

[2] At the top of page 2 of the text explaining the results of the Company's reconciliations, NEG reports a $661,375 under-collection of Storage Variable Product Costs. That reported under-collection is erroneous. They report a $2,449,837 over-collection of Storage Variable Product Costs during the 12-month period ended June 30, 2004. The $661,375 figure represents the end of period under-recovery balance for Storage Variable Product Costs. This inadvertent error has no impact on the overall results of the Company's reconciliations.

Q. HAVE YOU REVIEWED THE OPERATION OF THE COMPANY'S GAS PROCUREMENT AND ASSET MANAGEMENT INCENTIVES OVER THE LAST YEAR?

A. Yes, I have.

Q. HAS THE COMPANY'S GAS PROCUREMENT AND ASSET MANAGEMENT INCENTIVE PRODUCED THE DESIRED RESULTS?

A. Overall, I believe they have. Through a new Asset Management arrangement, NEG has established a new level of capacity release revenue that will help to establish a more rigorous benchmark for measuring subsequent Asset Management benefits for consumers and incentive rewards for the Company. Likewise, NEG has documented discretionary purchases that have produced noticeable additional gas cost savings for its customers. The comparatively small increases in GCR charges that NEG proposes in this proceeding, despite large increases in NYMEX natural gas prices, suggests at least a reasonable degree of success in the Commission's

Also, Schedule 6, page 1, of the Company's 2003-04 Gas Cost Recovery Reconciliation filing does not appear to reflect a full reconciliation of rates, usage and revenue for Supply Fixed Cost collections for the month of November 2003. Due to the implementation of new GCR charges during that month the unit charges should reflect a proration of the old and new charges. But, the Supply Fixed Cost Factors shown for several rate classifications for November 2003 are higher than either the new or the old factors. Mathematically, that is not possible. The Company's reconciliation of Supply Fixed Cost collections for that month is, thus, less than complete. On the other hand, the dollar impact of the observed differences in cost factors appears quite small, and probably does not warrant significant additional effort.

efforts to limit gas cost increases and control gas price volatility. However, there are certain elements of the Company's gas purchasing with which I have some concern.

Q. WHAT ARE THE ELEMENTS OF THE COMPANY'S RECENT OR PLANNED GAS PROCUMENT AND ASSET MANAGEMENT ACTIVITIES WHICH RAISE CONCERN?

A. My review of the Company's filing, data responses, and other related materials has brought focus to three concerns. Those are:

1. The comparatively large storage injections that NEG intends to make during the months of May and June of the coming year;

2. The extent of the Company's reliance on daily priced purchases of gas within each gas supply month to balance supply and demand; and

3. The Company's comparatively limited use of discretionary purchases within the parameters of the current gas procurement incentive structure.

Q. WHY DOES THE MAGNITUDE OF NEG'S PLANNED STORAGE INJECTIONS FOR THE MONTHS OF MAY AND JUNE RAISE CONCERNS?

A. Until the last couple of years, the months of May and June were typically considered opportune times to purchase gas at relatively low cost and inject it into storage for use during the following winter. However, pricing patterns for natural gas have changed dramatically, and over the last two years the months of May and June have been among the worst times to purchase gas for injection into storage at economically attractive prices. This change in the market is directly related to the amount of natural gas-fired generation that is now on the margin during summer air conditioning periods.

Since the amount of potential natural gas use by electric generators during summer months is now quite sizeable, the late spring period is now characterized by considerable speculation regarding the amount of gas that will actually be required for that purpose, and the resulting speculative buying activity has added considerable upward pressure and volatility to gas pricing during May and June. In each of the last two years, natural gas prices have peaked during those months, and my assessment of these markets suggests that this type of speculative buying of natural gas contracts in the months of May and June will only increase over the next few years.

Yet, despite the adverse nature of pricing in May and June, the monthly storage injections displayed on Schedule GLB-2, page 1, in the Company's September 1, 2004 filing indicate that NEG plans injections of over 800,000 Dth per month in each of those months.[3] NEG's planned storage injections do not surpass 480,000 Dth in any other month. If the Company has any flexibility to alter the timing of its storage injections and shift a greater percentage of planned storage injections to other months, it appears the Company would be well advised to use some of that flexibility.

Q. TO WHAT EXTENT HAS NEG RELIED ON DAILY PRICED PURCHASES OF NATURAL GAS DURING EACH GAS SUPPLY MONTH TO BALANCE GAS SUPPLY AND DEMAND FOR ITS FIRM SALES SERVICE CUSTOMERS?

A. Over each of the last two winters, NEG has relied on daily priced supplies for roughly **34%** of its total forecasted winter sales service requirements. See Exhibit BRO-5.

Q. WHY DOES NEG'S RELIANCE ON DAILY PURCHASES OF NATURAL GAS CONCERN YOU?

A. The large portion of daily priced purchases of natural gas puts the Company in the position of having to make significant volumes of gas purchases at prices that are likely to exhibit high levels of price volatility. For example, during January 2004,

[3] NEG's planned storage injections for May and June of 2005 total nearly 1.9 million Dth or roughly 42.5% of its projected annual storage injection requirements.

NEG made a number of daily priced purchases at prices in excess of **$40.00** per MMBtu. Moreover, during that month NEG purchased 309,513 Dth for a total cost of nearly $5.2 million. The average cost of those daily priced purchases was $16.75 per Dth. Although January 2004 is clearly an extreme example, I find that the highly volatile nature of pricing for daily purchases within a gas supply month is generally inconsistent with the gas procurement objectives that this Commission has pursued since the completion of ERI-1.

Q. PLEASE DESCRIBE NEG'S USE OF DISCRETIONARY GAS PURCHASES UNDER THE TERMS OF ITS GAS PROCUREMENT INCENTIVE.

A. Under the current gas procurement incentive structure, NEG's discretionary purchases of gas may not exceed 45% of its normal weather gas purchase requirements for any gas supply month, but the Company has not obligated to make that level of discretionary purchases. The only commitment NEG has with respect to discretionary purchases is to have a minimum of 70% of its supply requirements for a normal winter locked by October 20th of each year. Thus, up to 30% of the Company's normal winter requirements may be, and usually are, left for purchase during the subsequent winter months. Moreover, NEG is not required to make any specific levels of discretionary purchases for any individual month. The Company can, therefore, readily substitute daily purchases made during the month of supply for discretionary purchases made in advance of a gas supply month. Furthermore, when such substitutions are made, no incentives or penalties apply to gas purchases made during a gas supply month regardless of the price that NEG pays for such purchases. As shown in Exhibit BRO-6, the Company's discretionary gas purchases averaged only about 15% of forecasted sales service requirements for the November 2003 through March 2004 period, and only for November of that period did NEG's discretionary purchases exceed 20% of forecasted normal winter sales service requirements.

Q. ARE THERE CHANGES TO THE COMPANY'S GAS PROCUREMENT AND ASSET MANAGEMENT INCENTIVES THAT THE COMMISSION SHOULD CONSIDER AT THIS TIME?

A. Yes. I have two recommendations for such changes. One is procedural in nature. The other addresses the parameters in which the Company makes discretionary purchases.

Q. WHAT IS THE PROCEDURAL RECOMMENDATION TO WHICH YOU REFER ABOVE?

A. As presently structured, NEG's gas procurement and asset management incentives are computed annually on the basis of the Company's GCR period (i.e., November through October). The Division finds the use of that November – October period awkward since information necessary for the final determination of incentives is generally not available until after new GCR charges are already in place. This present structure unduly limits the Division's ability to assess the appropriateness of the final level of incentives built into the Company's charges for the subsequent GCR period. As an alternative, the Division asks that the Commission consider adjusting the period for which incentives are computed to conform with the Company's fiscal year (i.e., the 12 months ending June 30 of each year), and require NEG to file its incentive calculations at the same time that it files its Annual Gas Cost Recovery Reconciliation. The Division believes that adjusting the determination of incentives in this manner will facilitate its review of those determinations and will provide improved prospects for finality in the incentive amounts that are used to set GCR charges.

Q. HOW DO YOU PROPOSE TO ALTER THE PARAMETERS WITHIN WHICH THE COMPANY MAKES DISCRETIONARY GAS PURCHASES?

A. I propose a change in the structure of the incentive program that is targeted at partially closing a loophole in the current plan which has the effect of discouraging discretionary purchases while encouraging reliance on daily purchases within a gas supply month. In my assessment, that loophole also exposes NEG's firm gas service customers to high daily purchase prices in monthly gas purchases that could be avoided if NEG would make greater use of discretionary purchases in advance of each gas supply month.

Therefore, in an attempt to close, or at least narrow a loophole that the Division finds in the current incentive structure, I encourage the Commission to consider a modification of the current gas procurement incentives. One approach to close that loophole would be to limit the daily priced purchases that the Company can make within a gas supply month to the Company's actual sales of gas in excess of 95% of forecasted normal winter sales less actual LNG and propane sendout for the supply month. Any daily priced purchases made within a supply month in excess of this limit would be considered "discretionary purchases" and included in the determination of incentives and rewards relating to "discretionary purchases" under the terms of the Gas Procurement Incentive Program.

Q. DOES NEG'S FILING PROVIDE DEMONSTRATION THAT CHANGES AND ADDITIONS MADE TO ITS GAS SUPPLY PORTFOLIO SERVE TO MINIMIZE ITS COSTS OF GAS AND PROVIDE AN APPROPRIATE LEVEL OF FIXED COSTS

FROM WHICH TO MEASURE FIXED COST SAVINGS AND COMPUTE ASSET MANAGEMENT INCENTIVES?

A. The Company's filed September 1, 2004 testimony and schedules in this proceeding do not explicitly address the reasonableness of its projected fixed gas supply costs. Through informal discovery, however, the Company provided a multi-page spreadsheet which details the relationships between its supply capabilities and its forecasted design winter and design day requirements. Mr. Beland and Mr. Czekanski also took considerable time to walk me through that analysis and answer numerous questions regarding its content and implications. On the basis of my review of the additional analysis NEG has provided, I find that under design conditions the Company's gas supply and storage resources are heavily utilized, leaving little unused gas supply capability.[4] This leaves the potential that the Company would have excess supply capabilities under non-design conditions that could generate fixed cost savings through capacity release activities. However, that potential is addressed through the Company's forecasted capacity release credits, which appear to be reasonably in-line with its actual levels of capacity release

[4] It should be noted that NEG's design day and design winter analyses assume that incremental use per degree day in peak winter months is greater than average use per degree day for the winter season. This is an assumption not used in similar prior analyses. That assumption is also inconsistent with assumptions regarding the relationship between incremental degree days and incremental gas use that have been relied upon for ratemaking purposes. If gas use per degree day were assumed to be uniform throughout the winter, the Company's projected fixed costs for Supply and Storage may be subject to further scrutiny. However, the

revenue in recent years. Thus, I find little basis for questioning the reasonableness of NEG's fixed gas supply and fixed storage costs.

In the future, however, NEG should be required to explicitly address the reasonableness of its projected fixed gas supply and storage costs as part of its direct presentation in annual GCR filings.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING NEG'S FILING IN THIS PROCEEDING?

A. The Commission needs to understand and appreciate the circumstances in which NEG finds itself at this time with respect to its gas costs for the coming winter. The Company's GCR calculations in this proceeding use NYMEX prices for natural gas as of August 12, 2004 (i.e., two months ago) to estimate the costs for all "unlocked" gas volumes for its 2004-05 GCR period. Since August 12, 2004 NYMEX gas prices have risen sharply. As illustrated by the data in Exhibit BRO-5, NYMEX gas prices for the months of December 2004 through March 2005 have increased by an average of nearly 25%, and increases in the NYMEX prices for all other months of the 2004-05 GCR period average in excess of 11%. If those prices prevail throughout the coming GCR period, NEG's projected Supply Variable Costs can be expected to increase by more than **$23 million**. Thus, a continuation of NYMEX

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rationales and analytic explanations offered for the Company's assumptions in this proceeding do appear prices at or near currently levels could necessitate a GCR adjustment in either late 2004 or early 2005 if the Company's deferred gas cost balance is to be maintained within reasonable bounds. For this reason, I recommend that the Commission require NEG to provide not less than bi-weekly updates of its projected end-of-period deferred gas cost balance.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

reasonable.

Exhibit BRO - 1
Docket No. 3436
October 12, 2004

New England Gas Company
Docket No. 3436

Computed Increases in GCR Charges by Rate Classification

Rate Classification	Current GCR Rate ($/Therm)	NEG Proposed GCR Rate ($/Therm)	Increase (Decrease) $ ($/Therm)	Increase (Decrease) %
Residential				
Non-Heating	$0.8656	$0.8793	$0.0137	1.58%
Heating	$0.8656	$0.8793	$0.0137	1.58%
Commercial & Industrial				
Small	$0.8656	$0.8793	$0.0137	1.58%
Medium	$0.8561	$0.8718	$0.0157	1.83%
Large Low Load Factor	$0.8575	$0.8810	$0.0235	2.74%
Large High Load Factor	$0.8313	$0.8617	$0.0304	3.66%
Extra Large Low Load Factor	$0.8667	$0.9022	$0.0355	4.10%
Extra Large High Load Factor	$0.8213	$0.8386	$0.0173	2.10%
Marketer Charges	$0.0434	$0.0399	($0.0035)	-8.04%

New England Gas Company

Docket No. 3436

Bill Impact Analysis for Residential Non-Heating Customers (Nov 04 - Oct 05)

(Proposed Charges Reflect NEG's Pending Requests for Both GCR and DAC Increases)

Annual Use (Therms)	Proposed Charges	Current Charges	Difference	% Chg	Difference due to: Base Rates	GCR	DAC
115	$239.07	$234.96	$4.11	1.75%	$0.00	$1.01	$3.10
122	$249.05	$244.64	$4.41	1.80%	$0.00	$1.09	$3.32
130	$258.99	$254.31	$4.68	1.84%	$0.00	$1.18	$3.50
138	$268.91	$263.99	$4.92	1.86%	$0.00	$1.22	$3.70
145	$278.83	$273.60	$5.23	1.91%	$0.00	$1.29	$3.94
153	**$288.81**	**$283.31**	**$5.50**	**1.94%**	**$0.00**	**$1.38**	**$4.12**
161	$298.73	$292.97	$5.76	1.97%	$0.00	$1.46	$4.30
168	$308.64	$302.65	$5.99	1.98%	$0.00	$1.49	$4.50
176	$318.59	$312.28	$6.31	2.02%	$0.00	$1.58	$4.73
184	$328.53	$321.93	$6.60	2.05%	$0.00	$1.66	$4.94
191	$338.51	$331.63	$6.88	2.07%	$0.00	$1.74	$5.14

New England Gas Company
Docket No. 3436

Changes in Costs by GCR Cost Components (Excludes Reconciliation Amounts)

GCR Cost Component	Forecasted Annual Cost 2003-04 1/	Forecasted Annual Cost 2004-05 2/	Change $	Change %
Supply Fixed Costs	$ 27,570,113	$ 26,561,416	$ (1,008,697)	-3.7%
Storage Fixed Costs	$ 10,722,011	$ 11,309,415	$ 587,404	5.5%
Supply Variable Costs	$ 141,217,197	$ 171,192,715	$ 29,975,518	21.2%
Storage Variable Product Costs	$ 24,489,722	$ 26,029,061	$ 1,539,339	6.3%
Storage Variable Non-Product Costs	$ 2,760,431	$ 2,679,050	$ (81,381)	-2.9%
TOTAL	$ 206,759,474	$ 237,771,657	$ 31,012,183	15.0%

1/ Source: Schedule PCC-1, September 2, 2003, pages 2-5.

2/ Source: Attachment MJH-1, September 1, 2004, pages 2-5.

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Changes in Costs by GCR Cost Component (Including Reconciliation Amounts)

GCR Cost Component	Forecasted Annual Cost 2003-04 1/	Forecasted Annual Cost 2004-05 2/	Change $	Change %
Supply Fixed Costs	$ 26,656,998	$ 22,792,100	$ (3,864,898)	-14.5%
Storage Fixed Costs	$ 10,821,270	$ 9,546,777	$ (1,274,493)	-11.8%
Supply Variable Costs	$ 160,953,285	$ 187,088,855	$ 26,135,570	16.2%
Storage Variable Product Costs	$ 26,079,842	$ 25,152,625	$ (927,217)	-3.6%
Storage Variable Non-Product Costs	$ 2,146,435	$ 2,447,918	$ 301,483	14.0%
TOTAL	$ 226,657,830	$ 247,028,275	$ 20,370,445	9.0%

1/ Source: Schedule PCC-1, September 2, 2003, pages 2-5.

2/ Source: Attachment MJH-1, September 1, 2004, pages 2-5.

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Differences in Over (Under) Collection by GCR Cost Component
(2003-04 GCR Period)

GCR Cost Component	Beginning Balance 1-Nov-2003 1/	Projected Ending Balance 31-Oct-2004 2/	Net Over (Under) for 2003-04 GCR Period	Over (Under) as % of Forecasted Annual Cost 3/
Supply Fixed Costs	$ 945,701	$ 3,769,316	$ 2,823,615	10.6%
Storage Fixed Costs	$ (282,248)	$ 1,085,566	$ 1,367,814	12.6%
Supply Variable Costs	$ (20,853,786)	$ (15,896,140)	$ 4,957,646	3.1%
Storage Variable Product Costs	$ (2,102,278)	$ 876,436	$ 2,978,714	11.4%
Storage Variable Non-Product Costs	$ 610,199	$ 231,131	$ (379,068)	-17.7%
TOTAL	$ (21,682,412)	$ (9,933,691)	$ 11,748,721	5.2%

1/ Source: NEG, Annual Gas Cost Reconciliation, Docket 3436, August 3, 2004, Schedule 1, pages 1 and 2, November 2003 Actual Beginning Balances

2/ Source: Schedule PCC-3, September 1, 2004, pages 1 and 2, Forecested November 2004 Beginning Balances

3/ 2003-04 Forecasted Annual Cost by GCR Component from Exhibit BRO-3, page 2

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Differences in Over (Under) Collection by GCR Cost Component
(2004-05 GCR Period)

GCR Cost Component	Projected Beginning Balance 1-Nov-2004 1/	Projected Ending Balance 31-Oct-2005 2/	Net Over (Under) for 2004-05 GCR Period	Over (Under) as % of Forecasted Annual Cost 3/
Supply Fixed Costs	$ 3,769,316	$ 129,645	$ (3,639,671)	-16.0%
Storage Fixed Costs	$ 1,085,566	$ 42,577	$ (1,042,989)	-10.9%
Supply Variable Costs	$ (15,896,140)	$ 176,797	$ 16,072,937	8.6%
Storage Variable Product Costs	$ 876,436	$ 26,405	$ (850,031)	-3.4%
Storage Variable Non-Product Costs	$ 231,131	$ 2,759	$ (228,372)	-9.3%
TOTAL	$ (9,933,691)	$ 378,183	$ 10,311,874	4.2%

1/ Source: Schedule PCC-3, September 1, 2004, pages 1 and 2, Forecasted November 2004 Beginning Balances

2/ Source: Schedule PCC-3, September 1, 2004, pages 1 and 2, Forecasted October 2005 Ending Balances

3/ 2004-05 Forecasted Annual Cost by GCR Component from Exhibit BRO-3, page 2

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Differences in Costs Allocation Factors by GCR Cost Component

			Class Allocation Percentages					
GCR Cost Component	Allocation Factor		Residential and Small C&I	Medium C&I	Large LLF C&I	Large HLF C&I	Extra Large LLF C&I	Extra Large HLF C&I
Supply Fixed Costs	Design Winter Sales	1/	78.94%	14.78%	3.77%	1.36%	0.35%	0.81%
Storage Fixed Costs	Design Winter Throughput	2/	77.45%	15.63%	4.22%	1.56%	0.35%	0.79%
Supply Variable Costs	Forecasted Annual Sales	3/	77.73%	15.55%	3.63%	1.57%	0.29%	1.23%
Storage Variable Product Costs	Forecasted Annual Sales	3/	77.73%	15.55%	3.63%	1.57%	0.29%	1.23%
Storage Variable Non-Product Costs	Forecasted Annual Throughput	4/	76.12%	16.45%	4.14%	1.81%	0.28%	1.20%

1/ Source: NEG September 1, 2004 GCR Filing, Schedule PCC-1, Page 2, Line 14.

2/ Source: NEG September 1, 2004 GCR Filing, Schedule PCC-1, Page 3, Line 14.

3/ Calculated from Forecasted Sales by class, NEG September 1, 2004 GCR Filing, Schedule PCC-1, Page 12, Column (o), Lines 2-12.

4/ Calculated from Forecasted Sales by class, NEG September 1, 2004 GCR Filing, Schedule PCC-1, Page 12, Column (o), Lines 19-27.

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Comparison of Changes in Forecasted Sales by Month

	Forecasted 2003-04 Sales 1/ (MMBtu)	Forecasted 2004-05 Sales 2/ (MMBtu)	Forecasted Sales Increase (MMBtu)	% Increase
November	2,009,429	2,068,649	59,220	2.9%
December	3,347,385	3,237,235	(110,150)	-3.3%
January	4,733,438	4,818,748	85,310	1.8%
February	4,661,650	4,991,407	329,757	7.1%
March	4,051,827	4,264,515	212,688	5.2%
April	3,080,404	3,060,343	(20,061)	-0.7%
May	1,799,561	2,008,931	209,370	11.6%
June	1,044,377	1,002,537	(41,840)	-4.0%
July	823,284	800,325	(22,959)	-2.8%
August	782,384	757,306	(25,078)	-3.2%
September	835,458	657,318	(178,140)	-21.3%
October	1,148,647	1,061,272	(87,375)	-7.6%
Total	28,317,844	28,728,586	410,742	1.5%
Total Thru-put	28,966,726	29,335,819	369,093	1.3%

1/ Source: Attachment MJH-1, page 14, filed September 2, 2003.

2/ Source: Schedule PCC-1, page 12, filed September 1, 2004.

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NEG Reliance on Daily Priced Gas Purchases

Winter 2003-04

	Forecasted Sales 1/ (MMBtu)	Daily Priced Supplies 2/ (MMBtu)	Percent Daily Priced Supplies %
November	2,009,429	604,105	30.1%
December	3,347,385	1,517,281	45.3%
January	4,733,438	1,945,647	41.1%
February	4,661,650	944,711	20.3%
March	3,080,404	1,070,213	34.7%
Total	17,832,306	6,081,957	34.1%

1/ Source: Attachment MJH-1, page 14, filed September 2, 2003.

2/ Source: 10-08-04 E-mail Response from Gary Beland to Division oral data request

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NEG Discretionary Purchases (November 2003 - March 2004)

Month/Year		Forecasted Sales 1/ (MMBtu)	Discretionary Purchase Volumes 1/ (MMBtu)	% of Forecasted Sales
November	2003	2,836,228	621,582	21.9%
December	2003	3,643,878	657,011	18.0%
January	2004	3,840,980	626,177	16.3%
February	2004	3,616,698	400,987	11.1%
March	2004	3,581,582	369,596	10.3%
Total		17,519,366	2,675,353	15.3%

1/ Source: Docket 3436, Exhibit A to NEG Response to Commission Data Request Comm1-01, January 29, 2004.

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Potential Impact of Recent Gas Cost Increases

Month/Year		Unlocked Volumes	NYMEX Natural Gas Commodity Prices 8/12/2004	10/11/2004	Increase	% Increase	Projected Cost of Unlocked Volumes 8/12/2004	10/11/2004	Increase	% Increase
November	2004	1,582,509	$ 6.162	$ 6.993	$ 0.831	13.5%	$ 9,751,420	$ 11,066,485	$ 1,315,065	13.5%
December	2004	2,310,925	$ 6.592	**$ 8.164**	$ 1.572	23.8%	$ 15,233,618	$ 18,866,392	$ 3,632,774	23.8%
January	2005	2,325,946	$ 6.857	**$ 8.669**	$ 1.812	26.4%	$ 15,949,012	$ 20,163,626	$ 4,214,614	26.4%
February	2005	2,335,297	$ 6.827	**$ 8.609**	$ 1.782	26.1%	$ 15,943,073	$ 20,104,572	$ 4,161,499	26.1%
March	2005	2,335,727	$ 6.702	**$ 8.264**	$ 1.562	23.3%	$ 15,654,042	$ 19,302,448	$ 3,648,406	23.3%
April	2005	1,852,418	$ 6.107	$ 6.954	$ 0.847	13.9%	$ 11,312,717	$ 12,881,715	$ 1,568,998	13.9%
May	2005	1,526,472	$ 5.992	$ 6.704	$ 0.712	11.9%	$ 9,146,620	$ 10,233,468	$ 1,086,848	11.9%
June	2005	1,126,203	$ 6.010	$ 6.721	$ 0.711	11.8%	$ 6,768,480	$ 7,569,210	$ 800,730	11.8%
July	2005	779,338	$ 6.044	$ 6.744	$ 0.700	11.6%	$ 4,710,319	$ 5,255,855	$ 545,537	11.6%
August	2005	839,790	$ 6.057	$ 6.761	$ 0.704	11.6%	$ 5,086,608	$ 5,677,820	$ 591,212	11.6%
September	2005	778,731	$ 6.057	$ 6.726	$ 0.669	11.0%	$ 4,716,774	$ 5,237,745	$ 520,971	11.0%
October	2005	1,774,938	$ 6.087	$ 6.749	$ 0.662	10.9%	$ 10,804,048	$ 11,979,057	$ 1,175,009	10.9%
Total		19,568,294					$ 125,076,730	$ 148,338,393	**$ 23,261,663**	
Wtd Avg Commodity Cost per Dth							$ 6.392	$ 7.581	$ 1.189	**18.6%**